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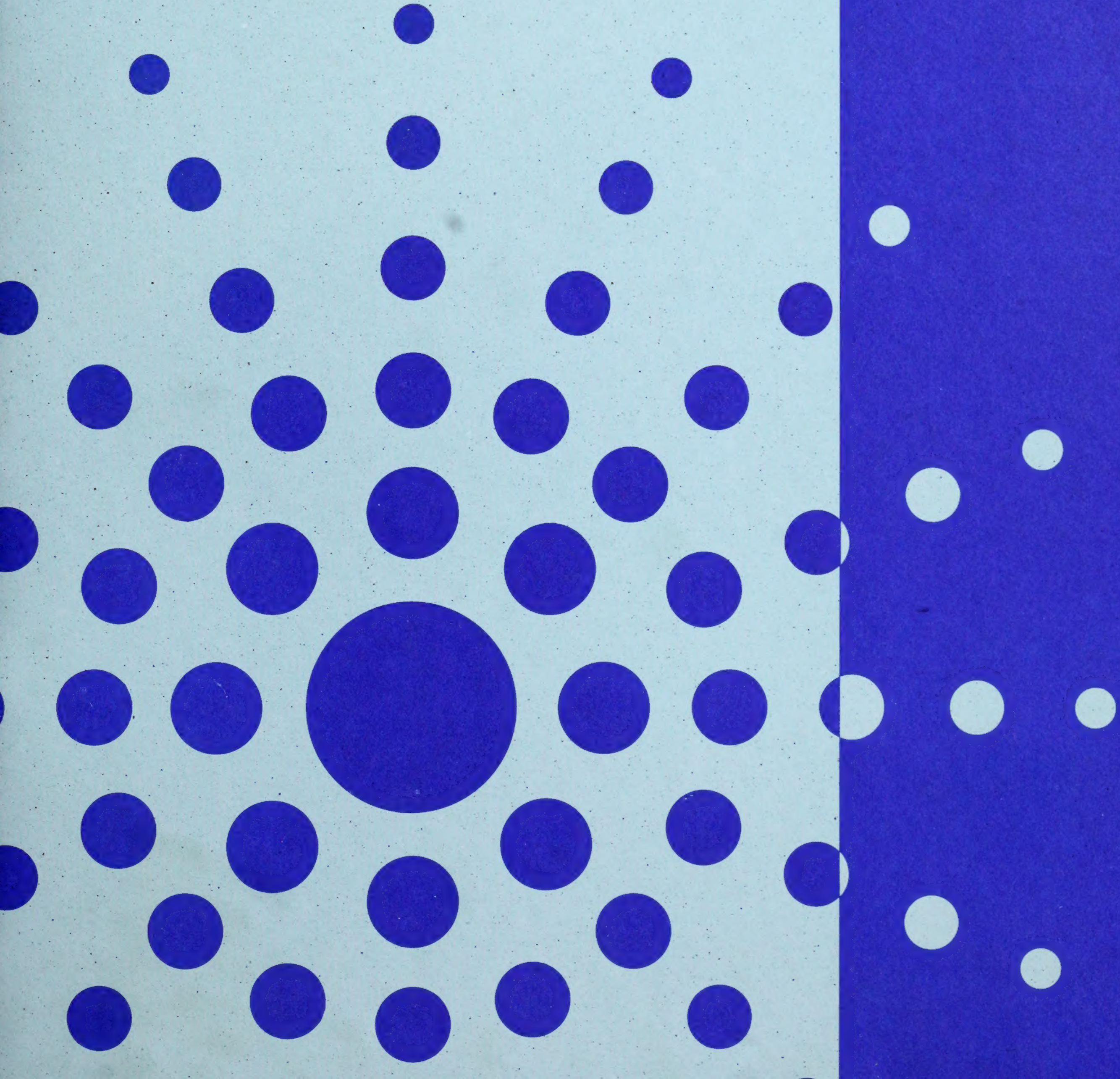
Alberta Energy

Annual Report

91/92



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April 1993

The Honourable Dr. David Carter
Speaker of the Legislative Assembly
Province of Alberta

Mr. Speaker:

I have the honour of submitting the Annual Report of the Alberta Department of Energy for the fiscal year ending March 31, 1992.

Respectfully submitted,

Patricia Black

Patricia L. Black
Minister of Energy

April 1993

The Honourable Patricia Black
Minister of Energy

Dear Minister:

It is my pleasure to submit the Annual Report of the Alberta Department of Energy for the fiscal year 1991-92. The report contains a summary of department activities, revenues and expenditures for the year.

Respectfully submitted,

M. F. Kanik
Deputy Minister

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Minister's Message

During the period covered by this annual report, and for the preceding two years, the Honourable Rick Orman served as Minister of Energy. He fulfilled the role with a diligence and enthusiasm that will be difficult to match. The trust and respect he earned, both inside government and with the many groups, organizations and individuals he dealt with, is solid testimony to his effective work. On behalf of the department and myself, I wish to thank him sincerely for his outstanding contribution.

A prolonged slump in the oil and gas industry posed a critical challenge for the Alberta Government in the 1991-92 fiscal year. The year witnessed a dramatic decline in industry activity and in the financial health of the oil and gas sector. In large part, the worsening condition was brought on by events beyond industry's control — pressure exerted by the global recession and the accompanying downward trend in commodity prices.

To deal with these changed circumstances, many firms carried out major corporate restructuring, which involved mergers, sales of assets, rationalizing operations and reducing workforces. The focus moved from growth to profitability, with firms concentrating on cost reductions and improved efficiency.

Recognizing that a healthy energy sector is important to the province's economic future, the government took steps to help the industry through this difficult period.

In November, the government announced the Crude Oil Exploration and Development Program, designed to encourage oil exploration and development activity. This program, based on suggestions made by the industry, provided royalty holidays for exploration, development and reactivated oil wells. It also granted "new oil" status without application to three different groups of oil wells.

Both industry and government recognized, however, that this program, no matter how helpful it might prove to be, was only a temporary measure. Some fundamental changes were required in the royalty system to reflect the drastically changed conditions the industry was experiencing.

Throughout the year the Department of Energy continued its comprehensive review of the royalty system, last restructured in the 1970s in anticipation of high oil and natural gas prices. The department collected a great deal of data that it shared with industry, and completed an initial analysis of royalty levels.

Another major concern in 1991-92 was the ongoing effort to restructure the important California gas market. Through a change in regulations, the California Public Utilities Commission (CPUC) is attempting to circumvent contractual arrangements and allow California consumers to buy gas directly from Alberta suppliers. In response to the Commission's moves, Alberta introduced a regulation to ensure that transportation rights under existing contracts were respected for members of the Alberta and Southern supply pool.

While Alberta recognizes the need to restructure existing contracts, the government believes changes should be made through negotiation between the parties involved rather than dictated by regulatory intervention. We are hopeful that a negotiated solution will be reached that provides fair and equitable treatment to Alberta producers.

Meanwhile, a significant advance was made on another front. In January, the governments of Alberta and British Columbia and the CPUC agreed to a Statement of Principles covering a general market framework for future gas trade with California.

As part of the government's ongoing effort to streamline operations, responsibility for the Electric Energy Marketing Act (EEMA) was transferred to the Department of Energy from the Alberta Electric Energy Marketing Agency. EEMA was implemented in 1982, primarily to reduce electricity rate disparities through equalizing wholesale costs of electricity across the province.

Toward the end of the fiscal year, a seven-member review panel from the private sector was named to examine EEMA and submit its findings to the government. After conducting hearings and seeking other public input, the panel was to determine whether EEMA's original objectives are being met and, if not, what alternatives should be considered.

Environmental matters continued to rank high in the department's priorities. In November, the Clean Air Strategy for Alberta (CASA) report was presented to the Ministers of Energy and Environment.

Prepared after extensive public consultation by a 13-member advisory group appointed 20 months earlier, the report provides an action plan for dealing with the environmental impacts of energy-related air emissions. The report's recommendations are being carefully reviewed by the government.

Environmental considerations also entered into the department's announcement of changes to the royalty structure for horizontal wells. This new technology not only has the potential to improve well productivity and enhance recoverable reserves but it is also more environmentally friendly than traditional vertical wells because it causes less surface disturbance.

It is a pleasure to report that work progressed during the year on the use of renewable sources of energy. Two additional wind projects, valued at a total of almost $18 million, were approved under the Southwest Alberta Renewable Energy Initiative (SWAREI). SWAREI was announced in December 1989 and began operations on April 1, 1990.

In closing this report, I wish to express my sincere appreciation to the staff and officials in the Department of Energy whose dedicated work so well serves both the government and the people of this province.

Patricia Black

Patricia Black
Minister of Energy

Organizational Structure

The Alberta Department of Energy has four basic functions. It grants mineral rights and administers mineral agreements on behalf of the Province; it provides the government with policy recommendations and advice on energy; it advises on, establishes and administers the fiscal regimes and royalty systems through which the people of Alberta — the resource owners — receive fair return on their resources; and it administers energy-related research, development and conservation programs.

In addition to the department, the Minister of Energy has responsibility for five reporting boards and agencies:

- Alberta Oil Sands Equity,
- The Alberta Petroleum Marketing Commission,
- Alberta Oil Sands Technology and Research Authority,
- Board of Directors of the Alberta Office of Renewable Energy Technology, and
- The Public Utilities Board.

The Energy Resources Conservation Board reports to Executive Council through the Minister of Energy.

The department is divided into five divisions, including Finance and Administration which also serves Alberta Forestry, Lands and Wildlife. In addition to the five divisions, the department's organizational structure includes the Communications Branch and Legal Services, both reporting to the Deputy Minister.

Mineral Resources Division — This division is responsible for developing and administering energy and other mineral leasing policies to optimize Alberta's mineral supply and the province's corresponding economic, environmental and employment interests. The division ensures that the Alberta Geological Survey effectively and efficiently supports provincial geological requirements. It consults with other governments on policies and administrative practices related to leasing and geological survey.

Mineral Revenues Division — This division is responsible for the management of programs established to generate and collect mineral revenues and for providing the assurance that these programs are consistent with provincial policies and the business environment. It manages a number of incentive programs that enhance exploration for minerals in Alberta and their extraction.

Markets, Supply and Industry Analysis Division — This division serves the Alberta public interest through analysis, policy development, making recommendations on legislation and programs, and providing information in the areas of markets, regulatory matters, industry financial performance, royalty policy, supply economics, resource revenue forecasting and electricity policy. The division provides advice on how to optimize the value and benefits that Albertans receive as owners of their mineral resources and consumers of oil, gas, coal and electricity.

Sustainable Energy Development Division — This division works to ensure the sustainable development of Alberta's energy resources. It provides policy advice and administers programs concerning energy efficiency. It also provides policy advice concerning environmental issues affecting energy production and use. It undertakes analysis and provides policy advice concerning development of non-conventional resources, including oil sands and renewable energy. It provides advice on research and technology and administers programs involving coal, hydrogen and renewable energy. The division has extensive liaison with other Alberta Government departments and agencies and with industry, non-governmental organizations and consumers.

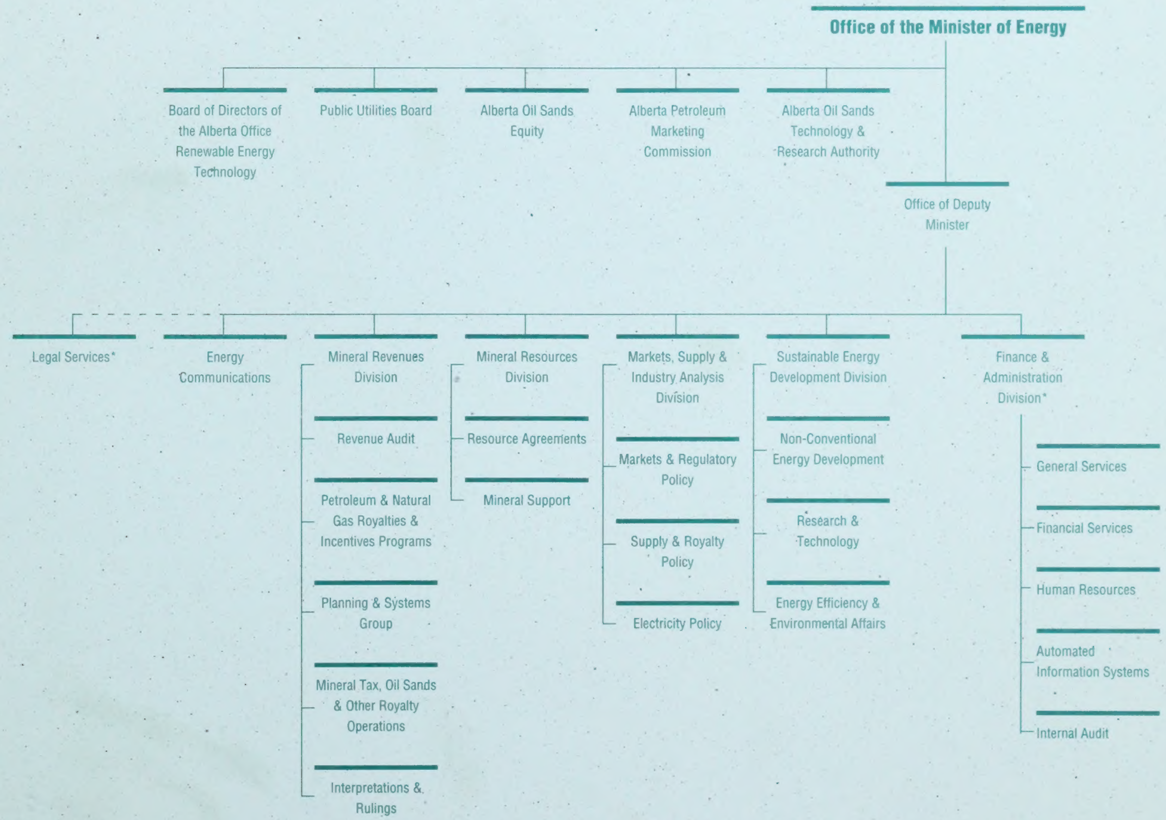
Finance and Administration Division — This division provides services to the departments of Energy, and

Forestry, Lands and Wildlife in the areas of finance, internal audit, automated systems, accommodations, records management, the Crown Land Registry, document and information support, and human resource programs. It provides a comprehensive structure for the financial and administrative functions required by both departments.

Communications — The Communications Branch provides an array of services to help ensure that the general public is kept informed of the department's activities and responsibilities. The branch prepares written material for release to the news media and is responsible for advertising, production of publications and development of displays. The branch provides writing and editing services and coordinates printing, graphic design and photography services. In cooperation with divisional staff, the branch develops and implements public awareness campaigns and responds to enquiries from the media.

Legal Services — This division provides legal advice and assistance on all matters pertaining to energy. It also serves the Department of Forestry, Lands and Wildlife.

Figure 1
Organization Chart for the Department of Energy


Office of the Minister of Energy
Board of Directors of the Alberta Office Renewable Energy Technology
Public Utilities Board
Alberta Oil Sands Equity
Alberta Petroleum Marketing Commission
Alberta Oil Sands Technology & Research Authority
Office of Deputy Minister
Legal Services*
Energy Communications
Mineral Revenues Division
Revenue Audit
Petroleum & Natural Gas Royalties & Incentives Programs
Planning & Systems Group
Mineral Tax, Oil Sands & Other Royalty Operations
Interpretations & Rulings
Mineral Resources Division
Resource Agreements
Mineral Support
Markets, Supply & Industry Analysis Division
Markets & Regulatory Policy
Supply & Royalty Policy
Electricity Policy
Sustainable Energy Development Division
Non-Conventional Energy Development
Research & Technology
Energy Efficiency & Environmental Affairs
Finance & Administration Division*
General Services
Financial Services
Human Resources
Automated Information Systems
Internal Audit

*Also serves the Department of Forestry, Lands and Wildlife

Revenues

As owners of the province's natural resources, the people of Alberta are entitled to a fair return on the production of oil, natural gas, coal and other minerals. As a representative of the people, the Alberta Government, through the Department of Energy, has the responsibility to develop and manage programs to determine these revenues and to collect them.

Figure 2
Energy Revenue

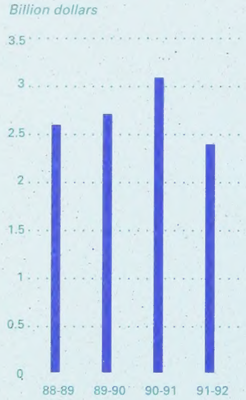
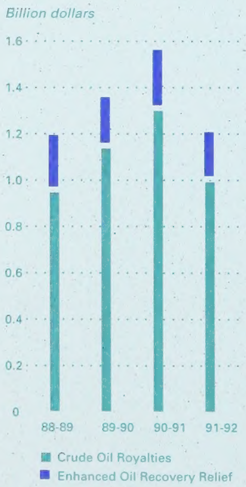


Figure 3
Crude Oil Royalties



Total Energy Revenues — Crown revenue in 1991-92 from all mineral resources was derived mainly from royalties and sales of Crown agreements for development of these resources. Net revenue for 1991-92 dropped to $2.38 billion from $3.06 billion the previous fiscal year, mainly because of significantly lower prices for crude oil and natural gas. (Figure 2)

Crude Oil Royalties — The volume of Crown conventional oil produced in 1991-92 declined by 5 million barrels from the previous fiscal year to a total of 273.3 million barrels. The gross Crown royalty share — Alberta's share before deductions — represented 23.5 per cent of the volumes produced during the fiscal year compared with 24.3 per cent in 1990-91. New oil — from reservoirs discovered after 1974 — represented 74.7 per cent of Crown volumes produced. Light and medium crude oil represented 82.6 per cent of total Crown production.

Net Royalty Volumes and Revenue — The net Crown royalty share is calculated by subtracting deductions for Enhanced Oil Recovery relief and the Crude Oil Royalty Holiday programs — which encourage exploratory drilling — from the gross Crown royalty share. The net share totalled 18.7 per cent, a volume of 51.1 million barrels. This compares with a rate of 18.6 per cent and a volume of 51.8 million barrels in 1990-91. Net royalty revenues for crude oil totalled $1 billion, a decrease of $300 million from 1990-91. (Figure 3) The revenue decline was attributable to a significant reduction in the selling price of a barrel of crude oil.

Enhanced Oil Recovery (EOR) — In a program to encourage incremental production of crude oil from a reservoir, royalty reductions may be applied when enhanced recovery techniques are used. These techniques increase the percentage recovery of the oil in place. They may consist of physical or chemical processes and add significantly to production costs.

The Conventional Enhanced Oil Recovery Royalty Relief Program, authorized under Section 11 of the Petroleum Royalty Regulation, is designed to reduce the costs and risks associated with EOR activities (tertiary recovery projects). Forty-eight EOR projects are currently operating in Alberta.

The Crown shares in certain costs by forgoing royalties on a portion of the oil production from the enhanced oil recovery project.

For the 1991-92 fiscal year, $170.2 million was provided in royalty volume relief with $9.5 million recovered in prior period cash adjustments. The net result was $160.7 million total relief provided to industry. Roughly 130,000 barrels per day of incremental oil was recovered from these projects during the year.

	1991-92	**1990-91**
	(millions)	
Crude Oil Royalty Revenue	1,199	1,526
Deduct		
Enhanced Oil Recovery Relief	161	201
Crude Oil Royalties (net of EOR)	**1,038**	**1,325**

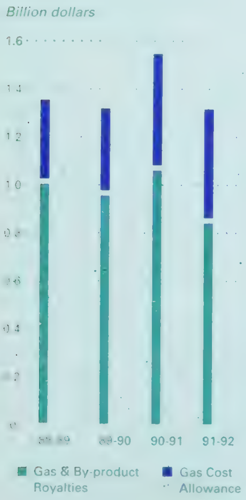
Synthetic Crude and Bitumen Royalties — Revenue from the production and sale of synthetic crude oil and bitumen in 1991-92 totalled $30.6 million. Revenue decreased by $8.4 million from 1990-91 as a result of lower synthetic crude and bitumen prices.

Natural Gas and By-product Royalties — Overall gross natural gas royalty revenues totalled $1.3 billion for 1991-92 compared with $1.5 billion in the previous fiscal year as producers throughout North America competed aggressively for limited markets. Net gas

Crown Conventional Oil is oil recovered under authority of a Crown lease, using primary production techniques.

Synthetic Crude Oil is produced from a heavy hydrocarbon called **"Bitumen"** saturated in beds of sand in the Fort McMurray area of northeastern Alberta. Other bitumen deposits are situated in the Wabasca, Peace River and Cold Lake areas of the province. At room temperature, bitumen has the consistency of very cold molasses. During processing, the carbon level of the bitumen is reduced and the hydrogen level increased. The result is synthetic crude which has properties similar to a high-grade conventional crude oil.

Figure 4
Natural Gas and By-product Royalties



royalties dropped by 23 per cent to $839 million from $1.08 billion the previous fiscal year. (Figure 4)

Gas Cost Allowance — Gas Cost Allowance is a deduction allowed by the Crown for gathering, compressing and processing the Crown's share of natural gas and associated by-products. It is deducted from royalties payable on a monthly estimated basis. The actual allowance is then calculated and reconciled for each calendar year. The allowance is subtracted from gross royalties to arrive at net royalties payable. In 1991, gas cost allowance totalled $481 million, up 5 per cent from $454 million in 1990.

Gas Royalties ($)	1991-92	1990-91	% Change
	(millions)		
Gas — New	643	742	-14
Gas — Old	306	346	-12
Pentane — New	132	154	-14
Pentane — Old	107	137	-22
Butane	46	53	-13
Propane	50	59	-16
Sulphur	36	43	-16
TOTAL	**1,320**	**1,534**	**-14**
Deduct			
Gas Cost Allowance	**481**	**454**	**5**
Net Gas Royalties	**839**	**1,080**	**-22**

Coal Royalties — Revenue from the production and sale of coal in 1991-92 totalled $26.4 million. Revenue increased by $11.8 million from 1990-91 as a result of higher production levels, stable prices and audit adjustments for prior periods.

Freehold Mineral Rights Tax — The Freehold Mineral Rights Tax is calculated on a calendar-year basis. The tax is based on the value of petroleum and natural gas produced from freehold lands .

For the 1990 taxation year, 5,026 taxable titles produced tax assessments of $78.8 million. The total consisted of $45.4 million from petroleum titles and $33.4 million from natural gas titles.

For the 1991 taxation year, 4,807 taxable titles produced tax assessments of $76.5 million consisting of $44.6 million from petroleum and $31.9 million from natural gas.

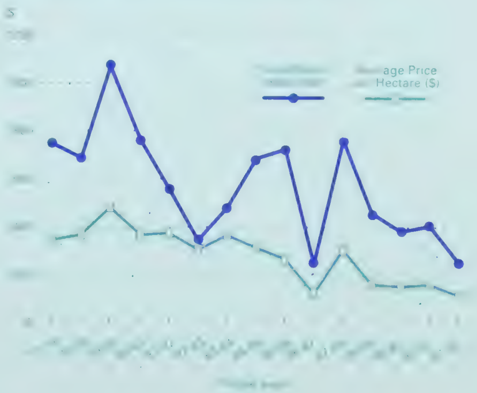
Net freehold revenues for 1991-92, after adjustments for relief and revisions for prior tax years, totalled $75.2 million, compared with $76.1 million in 1990-91.

Public Offering of Petroleum and Natural Gas Rights — Revenues from the public offering by the Mineral Resources Division of 5,336 petroleum and natural gas agreements during the 1991-92 fiscal year totalled $254.8 million, 38 per cent less than the previous year. These rights were sold for an average price of $124.56 per hectare, 28 per cent less than for 1990-91. A 15-year comparison of the revenues received for the public offering of petroleum and natural gas rights is shown in Figure 5.

Two areas attracted significantly higher-than-average revenues for the public offering of petroleum and natural gas rights. In the Battle River area, near Alliance, 18 parcels were sold for a total of just over $5 million. The average price per hectare for these parcels was approximately $1,074.

Continuing the trend set in 1990-91 in the Taber area, 22 parcels were sold for a total of just over $2 million with an average price per hectare of approximately $2,116.

Figure 5
Public Offering of Petroleum and Natural Gas Rights
Average Price per Hectare and Total Bonuses by Fiscal Year



Direct Purchases — Revenues from the direct purchase of 44 petroleum and natural gas agreements during the 1991-92 fiscal year totalled $554,000. These rights were sold for an average price of $75 per hectare.

The direct purchase of petroleum and natural gas rights was discontinued by the department on July 9, 1991. Such parcels may now be acquired through the competitive bid process.

Mineral Agreements

The Alberta Crown owns mineral rights covering approximately 81 per cent of the 66 million hectares in the province. Mineral rights in the province not owned by the Alberta Crown are termed "freehold." Whether publicly or privately owned, mineral resources in Alberta have always been privately developed. Before minerals owned by the Alberta Crown can be developed or recovered, the developer must hold an agreement for those minerals, although an agreement is not necessary to perform geophysical work.

Issued by the Mineral Resources Division, mineral agreements consist of permits, licences or leases. Figure 6 depicts the number of active agreements in place for the 1991-92 fiscal year and the number of hectares involved.

Petroleum and Natural Gas Agreements — The Mineral Resources Division issues two types of petroleum and natural gas agreements: licences and leases. Both types may be acquired at sales by public tender.

Petroleum and natural gas leases have a five-year term. Petroleum and natural gas licences, however, have terms of two, four or five years in the Plains, Northern and Foothills areas of the province, respectively. This feature recognizes that access to land is year-round on the Plains and seasonal elsewhere.

Public Offerings — During the 1991-92 fiscal year, 25 public offerings were held in Calgary and 5,336 petroleum and natural gas agreements were sold, down from 5,962 the previous year. These agreements, comprising both leases and licences, encompassed approximately 2 million hectares. Figure 7 depicts the number of agreements and hectares sold by public tender since 1977-78, the first full year under the current tenure system.

Direct Purchases — During 1991-92, 41 leases containing 7,419 hectares were issued by way of direct purchase. The department ceased to issue petroleum and natural gas rights by direct purchase on July 9, 1991.

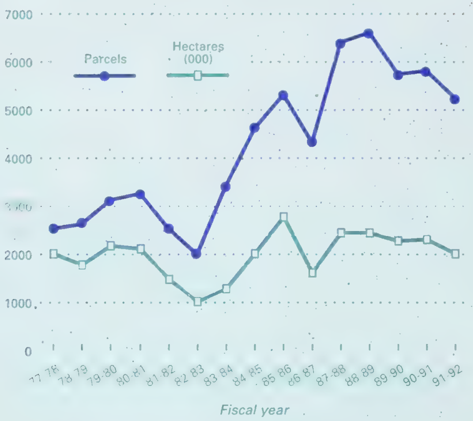
Primary Term Expiries — Shortly before a petroleum and natural gas lease reaches the end of its primary term, the lessee may apply to the Mineral Resources Division to have the lease continued, based on

Figure 6
Active Mineral Exploration and Development Agreements

	Number of Agreements				Thousand Hectares			
	March 31 1991	Issued	Cancelled	March 31 1992	March 31 1991	Issued	Cancelled	March 31 1992
Petroleum and Natural Gases								
Licences & Leases	61,733	5,975	5,174	62,534	26,472	2,561	2,805	26,228
Ammonite Shell Agreements	69	9	8	70	8	1	1	8
Oil Sands Leases	296	41	17	320	2,479	38	170	2,347
Coal & Coal Road Allowance	2,617	125	515	2,227	951	30	82	899
Metallic Minerals Exploration Permits	185	2	5	182	856	0	87	769
Metallic Minerals Leases	11	2	1	12	1	2	0	3
Other Minerals	152	8	17	143	34	1	6	29
Total	**65,063**	**6,162**	**5,737**	**65,488**	**30,801**	**2,633**	**3,151**	**30,283**

Freehold Minerals: Mineral rights not owned by the Alberta Crown are called "freehold." They cover about 19 per cent of the 66 million hectares of land in the province. Freehold rights are owned by the federal government within national parks and on behalf of Aboriginals within Indian reserves, by the Hudson's Bay Co. and national railway companies. They also result from federal grants to original homesteaders.

Figure 7
Petroleum and Natural Gas Parcels and Hectares (000) Sold



proven productivity. Petroleum and natural gas rights considered by the division to be productive are continued to the base of the deepest productive zone. Unproductive rights revert to the Crown.

During the 1991-92 fiscal year, 4,167 primary-term leases comprising 1,372,116 hectares, expired. Approximately 79 per cent, or 1,089,986 hectares contained in these leases were not proven productive and reverted to the Crown. Figure 8 shows a breakdown of actions on expiring leases.

Figure 8
Expiring Primary Term Petroleum and Natural Gas Leases in 1991-92 Fiscal Year

	Leases	Hectares	Per Cent of Total Hectares
Continued Based on Proven Productivity	794	211,117	15
Continued Based on Drilling Operations Near End of Term	97	27,760	2
Continued As Potentially Productive	189	39,925	3
Term of Lease Extended	8	3,328	1
Not Continued (Cancelled)	3,079	1,089,986	79
Total	**4,167**	**1,372,116**	**100**

Continued Leases — The Mines and Minerals Act provides for the monitoring of petroleum and natural gas leases that have been continued. When productivity of a lease is in doubt, the Minister may serve a one-year notice stating that the lands or rights will revert to the Crown unless the lessee can provide evidence of productivity. During the 1991-92 fiscal year, 1,015 non-productivity notices were served, affecting 220,934 hectares.

In addition, 992 non-productivity notices served in the 1990-91 fiscal year expired, affecting 221,637 hectares. As a result, 14 wells were drilled and an additional 57 wells re-entered or recompleted prior to the end of fiscal 1991-92. Seventy-five per cent of the affected hectares reverted to the Crown and thereby became available for further acquisition.

Offset Drilling Obligations — When a well is drilled on freehold rights and is put on production, it has the potential to drain petroleum or natural gas from adjacent Crown mineral rights. This creates an offset drilling obligation for Crown leases. To protect the interests of Albertans, the Crown lessee is given the option of drilling a well, paying compensatory royalty in lieu of drilling, or surrendering lands or rights to satisfy the offset obligation.

During the 1991-92 fiscal year, 551 freehold oil wells were reviewed and 52 oil offset default notices were served. As a result of these notices, 22 lessees elected to pay compensatory royalty, 19 surrendered the petroleum and natural gas rights, 7 drilled wells and 4 notices were withdrawn.

During the fiscal year, 1,034 petroleum and natural gas posting requests were reviewed, and 30 oil offset and 17 gas offset notices were served. As a result, 20 lessees elected to pay compensatory royalty, 9 drilled wells, 14 surrendered the petroleum and natural gas rights, 2 notices were withdrawn, and 2 were extended.

Unit Agreements — A number of parties, including the Alberta Government, can have an interest in a single oil or gas pool. Unit agreements are useful tools for achieving the highest possible oil and gas recovery while ensuring that all parties recover an equitable share of the resource.

All proposed unit agreements in the province are reviewed, negotiated and executed on behalf of the Minister by the Mineral Resources Division. During the 1991-92 fiscal year, 15 new unit agreements became effective and 4 existing ones were enlarged. At fiscal year-end, the Alberta Government was party to 582 units.

During the fiscal year, the division continued to participate in negotiations for a new model unit agreement being developed by the Petroleum Joint Ventures Association. The model agreement was ratified by industry and government and will replace the modified 1972 version now used.

Oil Sands Leases — During the 1991-92 fiscal year, the Mineral Resources Division administered 320 oil sands leases. One-third of these leases are in their second 21-year term and will expire between 1996 and 2011. Each second-term lease is required to be in production at a specified capacity in order to enter its third term. These leases encompass approximately half of both surface-mineable and non-surface-mineable oil sands reserves.

During the fiscal year, only 2 second-term oil sands leases produced at or above their prescribed capacity. Four other second-term leases produced at less than their specified capacities, while the balance did not produce at all.

The division recognizes that those who are prepared to commit to production during the third term should be allowed to retain reserves under lease. The division has been working with industry to revise the Oil Sands Regulation. In June 1991, Cabinet endorsed the new Oil Sands Regulation. As a result, the first-ever public offering of oil sands leases was held in February 1992 and 38 leases were sold for $7 million.

Coal and Other Minerals — The Mineral Resources Division administered 2,101 existing coal leases comprising 894,000 hectares during the 1991-92 fiscal year. This compares with 2,716 leases covering 956,000 hectares the previous year. It did not issue any new coal leases.

The division received 5 applications for metallic mineral exploration permits, comprising 3,260 hectares of rights, located primarily in northwestern Alberta.

The division administered 70 ammonite shell agreements comprising 7,860 hectares of rights during the fiscal year and granted 9 applications for an additional 900 hectares of rights. Ammonite shell of jewellery quality is Alberta's gemstone and is unique to the province. It is also a palaeontological resource under the Historical Resources Act.

A total of 99 quarriable mineral leases comprising 16,320 hectares of rights were administered by the division during the fiscal year. In addition, the division administered 11 salt agreements comprising 5,100 hectares.

Conventional and Non-conventional Oil

The average price for crude oil (West Texas Intermediate at Cushing, Oklahoma) was US $20.77 over the 1991-92 fiscal year compared with $24.49 the previous year. The global oil market was still adjusting to the shock of the Persian Gulf crisis. Although the crisis officially ended with Iraq's surrender in January 1991, crude oil exports from Iraq and Kuwait continued to be disrupted.

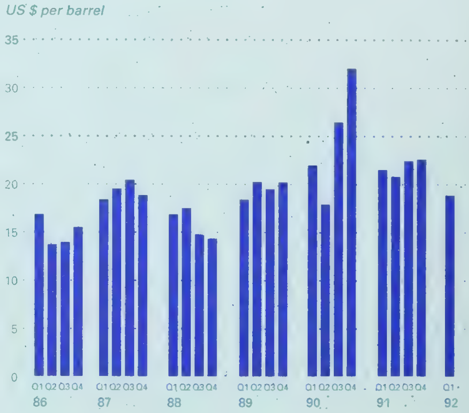
The embargo against Iraqi oil exports remained in effect during the entire 1991-92 fiscal year. Kuwait gradually rebuilt portions of its destroyed oil production facilities, enabling production to reach about 700,000 barrels a day by March 1992. Despite the disruption in supplies from Iraq and Kuwait, the remaining 12 members of the Organization of Petroleum Exporting Countries were able to produce at almost full capacity throughout the period. Prices remained fairly strong and stable through the first half of the fiscal year, ranging mostly between US $20 and US $22. While the disruption to oil exports from Iraq and Kuwait put considerable upward pressure on prices, several factors helped to moderate this trend. The most important factor was a weak global demand for crude oil resulting from economic slowdowns in many industrialized countries. Another factor through the first half of the fiscal year was an abnormally high level of global oil stocks.

The average price during the second quarter of the 1991 calendar year was US $20.75. The price strengthened slightly in the third quarter to US $21.66. The increase resulted partly from a seasonal rise in demand for oil. Demand for gasoline increases during summer months, while demand for winter heating stocks rises significantly during the fall.

During the fourth quarter of the calendar year, prices reached a peak of US $24.14. By early November after the build-up of winter heating stocks, prices started to decline. By the end of December, prices fell to below US $19. The fourth quarter average price was US $21.75.

Prices continued to decline in early January 1992, reaching a low of $17.86. They slowly began to strengthen through late January as oil stocks were gradually reduced. The oil market also expected OPEC to substantially reduce its overall production ceiling at a meeting scheduled for mid-February. Although a cut in the OPEC production ceiling was announced, market traders apparently did not feel that it was sufficient to significantly reduce the global excess supply of crude oil and products. Consequently, prices quickly fell from around US $19.50 to just above US $18. As stocks continued to gradually decline, prices slowly rose, closing the first quarter of the 1992 calendar year in the low US $19 range. The average for the quarter was US $18.92. (Figure 9)

Figure 9
West Texas Intermediate Crude Oil Prices



Crude Oil Production — Alberta produced a total of 454 million barrels of crude oil during the 1991 calendar year compared with 459 million barrels in 1990.

Conventional crude oil	
Light-medium grades	257 million barrels
Heavy oil	70 million barrels
Total	**327 million barrels**
Synthetic crude from oil sands	
Syncrude	60 million barrels from Syncrude
Suncor	22 million barrels from Suncor
Total	**82 million barrels of synthetic crude**
Crude Bitumen	**45 million barrels**

Fifty-seven per cent of total crude oil production consisted of light- and medium-grade oil, 15 per cent heavy oil, 18 per cent synthetic crude and 10 per cent bitumen.

Average productivity, measured in barrels per day, varied from 1990:

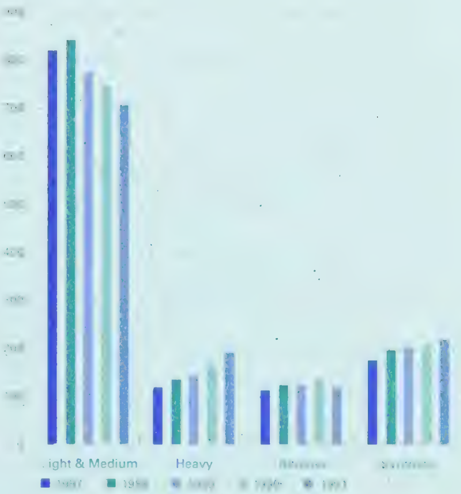
- Conventional light and medium crude oil dropped by 5 per cent to 705,000 from 739,000.
- Conventional heavy oil climbed 11 per cent to 193,000 from 174,000.
- Synthetic crude oil climbed 8 per cent to 225,000 from 208,000.
- Crude bitumen declined 10 per cent to 123,000 from 135,000.

Figure 10 provides a comparison of daily production statistics for crude oil production over a five-year period.

Reserves and Potential — Remaining established reserves of conventional crude oil that can be retrieved with current technology totalled 2.9 billion barrels at the end of the 1991 calendar year, down 9.4 per cent from the 1990 level of 3.2 billion. At current production levels, this would represent a conventional crude oil supply of slightly less than 9 years, although new discoveries tend to maintain reserve levels. The remaining ultimate potential for production of conventional crude oil was estimated by the Energy Resources Conservation Board at 6.6 billion barrels.

Remaining established reserves of crude bitumen that can be retrieved with current technology from deposits under active development include 2.8 billion barrels for surface-mining projects and 0.3 billion barrels for in situ projects. These represent a supply of 25 years at 1991 production levels. The remaining ultimate potential for production of crude bitumen was 305 billion barrels at year-end 1991.

Figure 10
Average Daily Production of Crude Oil



Crude Oil Exploration and Development Program — In November 1991, Energy Minister Rick Orman announced the Crude Oil Exploration and Development Program. This initiative is designed to increase oil exploration and development activity in Alberta. It provides a royalty holiday to new and reactivated wells.

Exploration oil wells drilled between November 1, 1991 and March 31, 1992 qualify for a two-year royalty holiday. Exploration wells drilled between April 1, 1992 and March 31, 1993 qualify for a one-year holiday. The qualification period for the two-year holiday was extended to April 1, 1993 for the Northern and Foothills regions, due to access restrictions. A maximum royalty exemption of $1 million per well is permitted.

Development oil wells drilled between November 1, 1991 and March 31, 1993 qualify for a one-year holiday. A maximum royalty exemption of $400,000 per well is permitted.

In Situ Recovery refers to on-site methods to extract the fuel component of a deposit. While shallow oil sands deposits can be removed by surface mining, dense heavy oils and deeply-buried bitumen require in situ techniques before they can be brought to the surface. These include thinning the oil to make it mobile and application of pressure to make it flow.

Reactivated Oil Well Holiday — Oil wells that have been inactive since August 30, 1990 and are reactivated between October 31, 1991 and April 1, 1993 qualify for a five-year holiday. The royalty exemption applies only to a well's first 25,000 barrels of production.

Horizontal Drilling — The government announced changes to the royalty structure for horizontal wells in April 1991. The Horizontal Well Petroleum Royalty Regulation was introduced to encourage the use of new technology for the recovery of crude oil and bitumen. Under the program, the definition of horizontal well productivity rates has been changed, thereby providing royalty relief. The program was introduced on a temporary basis to allow time for data to be collected for evaluation of the economics associated with horizontal well technology in Alberta. Horizontal wells drilled between December 31, 1990 and January 1, 1993 qualify for royalty relief.

Royalty Review — The three programs described above were designed as interim measures while the department continues a comprehensive review of its fiscal regime for oil and gas. Under the long-term review, emphasis was placed on modelling the oil and gas industry and Alberta's oil and gas plays. These modelling tools allow the department to measure the profitability and financial health of the industry under different fiscal structures and economic conditions. Plans were developed for these models to be used as the basis for a complete overhaul of Alberta's royalty regime in the following fiscal year.

Non-conventional Oil Development — As the supply of conventional oil in North America is depleted, consumers will be forced to turn to non-conventional sources of petroleum to avoid a growing dependence on Middle Eastern oil. Fortunately, Alberta has very large deposits of oil sands. These oil sands underlie about 77,000 square kilometres in the province and contain about 1.7 trillion barrels of oil in place.

In encouraging the development of this oil sands resource, the Government of Alberta's main objective is to promote sustainable and environmentally sensitive development using the best technology. Alberta's strategy of oil sands development is aimed at unlocking our massive resource potential for the long-term prosperity of the province.

During 1991-92, oil sands production accounted for approximately 23 per cent of Canada's total oil production.

1991-92 Performance and Activity — Prices for heavy oil and bitumen remained low during 1991-92 although they showed signs of improvement late in the fourth quarter. Differentials between light and heavy crudes remained high.

The Alberta Government continued its involvement in Syncrude and the Bi-Provincial Upgrader during 1991-92. Alberta's participation in the OSLO Commercial Project was suspended in early 1992 once engineering studies were completed. All three projects are described in the Appendix.

Syncrude broke its yearly production record in 1991, producing over 60 million barrels of synthetic crude oil. Suncor also achieved record production levels in 1991, producing over 22 million barrels of synthetic crude oil. (Figure 11)

Exploration Wells qualifying for a royalty holiday under this category generally include wells drilled more than 2.4 kilometres from the nearest well capable of production from the same zone.

Horizontal Drilling Technology has the potential to improve well productivity and enhance reserves recovery. Unlike a standard vertical well which may only be able to tap a small portion of an oil pool, horizontal wells turn at an angle when a pool is reached. This means that horizontal wells usually contact a larger area within the pool and may reach into harder-to-drain areas with less cost than would be the case with additional vertical wells

Heavy Oil sometimes requires special production techniques such as steam injection to extract it from underground formations.

Natural Gas

The 1991-92 fiscal year brought mixed results for Alberta natural gas. Although prices dropped, the industry made impressive gains in penetrating new markets, especially in the U.S. northeast.

Prices — A continuing oversupply of natural gas throughout North America resulted in lower natural gas prices during the 1991-92 fiscal year. Domestic prices had been dropping since 1990, partly because limited export pipeline capacity constrained producers' access to markets. The average market price for Alberta gas during the fiscal year dropped to $1.34 per thousand cubic feet (Mcf) from $1.52 Mcf in 1990-91.

Markets — Alberta's overall gas sales rose by five per cent in 1991-92 from the previous fiscal year, largely due to an increase in exports, especially to the U.S. northeast. TransCanada PipeLines expanded its system and the connecting Iroquois Gas Transmission System to the northeast was readied for opening.

Sales to California and the U.S. Pacific northwest continued at near the full capacity of the pipelines. Canadian domestic consumption of gas climbed only slightly due to a weak economy and a warmer-than-normal winter.

The U.S. Federal Energy Regulatory Commission announced plans to release Order 636. It requires pipelines in the United States to provide fair and equal access to all shippers seeking to move natural gas. The intent of the order is to remove the competitive advantage that pipelines have enjoyed due to their integration of transportation and sales functions.

Order 636 will unbundle the merchant and transportation roles of interstate pipelines to improve access to transportation for both buyers and sellers of natural gas. About 29 per cent of long-term Canadian exports are sales to pipelines.

Production — Natural gas production in 1991 totalled 3.3 trillion cubic feet (Tcf), up from 3.1 Tcf the previous year. Gas volumes for export sales in 1991 totalled 1.45 Tcf, an increase from 1.28 Tcf in 1990. Sales to other Canadian provinces in 1991 totalled 907 billion cubic feet (Bcf), down from 960 Bcf in 1990. Intra-Alberta sales increased to 937 Bcf from 920 Bcf the previous year.

Reserves and Potential — At calendar year end 1991, remaining established reserves totalled 57.7 Tcf, against 58.5 Tcf in 1990. Alberta's reserve-to-production ratio was approximately 17.5 years. The remaining ultimate potential for production of marketable natural gas was estimated by the Energy Resources Conservation Board to be 107 Tcf.

NOVA — In June 1991, the Minister of Energy asked the Energy Resources Conservation Board to review the operation of NOVA's natural gas transmission system. The hearing focused on the need for new pipeline construction in Alberta by NOVA and the cost of such construction, NOVA's terms of service and operating practices and the method of resolving outstanding issues. Participants in the process expressed concern with the existing complaint-based method of regulation.

TransCanada PipeLines — The National Energy Board (NEB) gave final approval to TransCanada PipeLine's $2.6-billion expansion. The capacity of the system increased by 832 million cubic feet a day (MMcf/d), including 576 MMcf/d to the U.S. northeast market on the Iroquois pipeline.

The NEB began a hearing in April 1991 into TransCanada's application to build the Blackhorse Extension. The proposed $38.9-million extension would connect the existing Niagara line to the Empire State Pipeline to deliver natural gas to central and western New York State. The NEB denied the application, although it subsequently reversed that decision.

Natural Gas Marketing Act — The Natural Gas Marketing Act was amended in June 1991. The Act applies to Alberta producers supplying gas to aggregators under netback contracts. The amendment ensures that Alberta aggregators have the

Aggregators are shippers who purchase gas supplies from a number of producers, establishing a supply pool. Gas is sold to downstream customers from this pool.

Netback Contracts are pricing agreements between producer and shipper. They provide that the price paid by a shipper to a producer will be calculated based on the price obtained by the shipper when he re-sells the gas to a downstream buyer.

right to vote on the terms and conditions of contractual arrangements involving the resale of natural gas as well as the price.

PGT/Altamont — Throughout the fiscal year, planning proceeded on two projects to increase Alberta gas deliveries to California. The $573-million Altamont project proposed to carry 700 MMcf/d of gas by way of Montana, Wyoming and the Kern River pipeline into southern California. Pacific Gas Transmission (PGT) proposed an $809-million expansion to carry 755 MMcf/d to northern and southern California and 148 MMcf/d to the U.S. Pacific northwest.

Because of uncertainly about whether both projects would be required, NOVA requested letters of credit from each participant. This provided backstopping for NOVA to proceed with the separate expansions required for each proposed pipeline. Letters of credit for both projects were provided to NOVA in December 1991.

Due to concern about the timing and need for two projects, the Minister of Energy asked the Energy Resources Conservation Board to call for information on both the Altamont and PGT proposals. This allowed industry participants to gain full access to relevant information so the market could decide which project should proceed.

Construction of Pacific Gas Transmission's pipeline expansion in Washington and Oregon was on schedule for its planned November 1, 1993 start-up. Altamont announced a one-year construction delay with new start-up scheduled for November 1994.

The Pacific Gas and Electric Company announced on September 5, 1991 that agreement in principle had been reached for the sale of PGT to TransCanada PipeLines. The sale will not take effect until completion of restructuring of the present Canada-California gas trade on the existing PGT line. The sale will not affect construction of the PGT expansion.

California Sales — During the year, the Department of Energy and the Alberta Petroleum Marketing Commission conducted negotiations with the California Public Utilities Commission (CPUC) to resolve ongoing regulatory differences. These differences arise from a number of CPUC decisions that threaten Alberta's existing long-term supply contracts for the California gas market. Alberta actions during the year were intended to ensure that commercial parties involved have the opportunity to conclude agreements which reflect the rights and costs associated with change. Developments during the fiscal year included the following:

- In December 1991, Alberta announced the NOVA Terms of Service Regulation. It was introduced in response to CPUC actions to accelerate change independent of commercial negotiations.
- In December 1991, Alberta entered special gas talks with CPUC, the British Columbia Department of Energy and Mines and representatives of the United States and Canadian governments. These talks resulted in a Statement of General Principles outlining a framework for future gas trade with California.
- CPUC released its Division of Ratepayer Advocates report on the "reasonableness" of gas and electric operations for 1988, 1989 and 1990 by Pacific Gas & Electric Co. (PG&E). The report investigated PG&E's purchases of Canadian gas through its corporate affiliates — Pacific Gas Transmission Company and Alberta & Southern. The report concluded that PG&E had been paying too much for its Canadian gas supplies during 1988, 1989 and 1990.
- On February 4, 1992, the National Energy Board (NEB) ruled that companies exporting gas at Kingsgate, B.C. — export point for most Canadian gas destined for the northern California market — must obtain prior permission from the NEB. This measure was aimed at preventing displacement of Canadian long-term gas volumes to the northern California market with spot sales.

- Michael Stewart, President of Ballinacurra Associates Ltd., acted as facilitator in discussions during 1991 with PG&E on new market structures and contracts. He was succeeded by Dale Lucas, President of J. Makowski (Canada) Ltd. Negotiations continued into the next fiscal year.

Removal Permits — More than 1,000 applications for natural gas removals were processed at the Department of Energy. The Energy Resources Conservation Board and the Department of Energy work together to issue long- and short-term removal permits required for the export of natural gas. Long-term applications require Cabinet approval, while short-term (two years or less) require approval by the Minister of Energy.

Coal and Other Minerals

Alberta has extensive coal resources and produces three general types of coal — sub-bituminous, thermal bituminous and metallurgical — at 11 major mining locations.

- Sub-bituminous coal is produced at 6 mines for use by Alberta utilities. These mines, all located in the Plains region, provide the basic fuel for almost 90 per cent of Alberta's electric power generation. Highvale, Canada's largest coal mining operation, produces more than 20 per cent of the country's coal.
- Thermal bituminous coal is produced at 2 mines. This high-heat value, low-sulphur coal is exported to Japan and Ontario where it is used in thermal power plants.
- Metallurgical coal is produced at 3 mines. Most of it is exported for use by the steel industry in Japan. Other markets include Korea and Brazil.

Prices — Export prices for metallurgical coal are largely determined by a consortium of Japanese steel manufacturers, the single largest buyer in the market. Prices for export thermal bituminous coal are largely determined by Japanese utilities and Ontario Hydro.

Prices for metallurgical and thermal coal dropped 2 to 3 per cent in 1991 from the previous year. Prices for sub-bituminous coal, used by Alberta electric utilities, rose 6 per cent over the same period.

Production — Alberta's deliveries of marketable coal totalled 32.5 million tonnes in the 1991 calendar year, up 6.5 per cent from 30.5 million tonnes the previous year. Marketable deliveries of bituminous metallurgical coal increased to 7.8 million tonnes from 6.1 million. Bituminous thermal deliveries increased to 3.2 million tonnes from 3.1 million. Sub-bituminous deliveries increased to 22.2 million tonnes from 21.3 million.

Coal Supply Development — The department began a review of Alberta's coal royalty structure during the year. The coal royalty formula is based on costs, revenues and investment. Royalty share increases as a mine achieves greater economic success.

Coal Market Development — In March 1992, Ontario Hydro agreed to purchase 1.2 million tonnes of coal a year for three years from Luscar Ltd. of Edmonton. The delivered cost of this coal is competitive with coal originating in the eastern U.S.

The Alberta Government continues to work with other provinces, the federal government and industry to improve the competitiveness of western Canadian coal in the Ontario market. Formed in 1987, the Action Committee on Western Canadian Low-Sulphur Coal to Ontario consists of the Deputy Prime Minister and the premiers of British Columbia, Alberta, Saskatchewan and Ontario.

The committee is also charged with reviewing all regulatory and fiscal aspects of coal transportation and pursuing product-oriented research programs related to coal technologies. Alberta has assumed the lead role for most technical projects.

Research and Technology — The department supports technology developments needed by the coal industry to remain competitive in domestic and international markets and to provide new products for these markets. Research is currently focused on:

- Development of technologies to allow coal to be burned more cleanly,
- Technologies to enhance the competitiveness of coal, and
- Creating value-added products from coal.

Integrated Gasification Combined Cycle — Integrated Gasification Combined Cycle (IGCC) is a process for using coal to generate electricity while producing fewer emissions than by conventional coal-burning processes. It is more efficient and capable of producing less carbon dioxide per unit of electricity generated.

In 1991, the department was one of several sponsors of an investigation into the economic and technical feasibility of building and operating an IGCC plant in Canada. A preliminary design was created that should be capable of reducing emissions to one-fifth of currently-allowed limits, and lowering carbon dioxide emissions by 15 to 20 per cent relative to power plants now used in Alberta.

Hydrogen Research — The Alberta Hydrogen Research Program, funded jointly by industry and government, aims to make Alberta's energy industry more competitive. The program's overriding objective is to use hydrogen as a principal link for integrating the energy resource industry and developing Alberta's industrial base. Thus far, 20 research projects have been carried out. The program is focused on two aspects: methods for producing hydrogen that are less expensive than the current steam-methane reforming process and opportunities to use hydrogen in a more efficient manner in existing or new industries in Alberta.

Sulphur — Alberta is a world leader in the production of sulphur. Ninety per cent of current production is from gas processing plants, which recovered 5 million tonnes in 1991. Oil sands plants recovered 550,000 tonnes from bitumen production while oil refineries recovered 17,000 tonnes.

Most of Alberta's output is exported as pure elemental sulphur. It is used in the manufacture of sulphuric acid for industry and in the production of fertilizer. In 1991, the average North American price for sulphur was $55.12 a tonne.

The remaining established reserves of sulphur in Alberta at calendar year-end 1991 were estimated by the Energy Resources Conservation Board at 102 million tonnes. Of this total, 86 million tonnes are recoveries from natural gas and 16 million tonnes from bitumen. The remaining ultimate potential for sulphur production is much greater: 221 million tonnes from gas and 2,195 million tonnes from bitumen.

Electricity

Alberta has a mix of investor-owned and municipally owned electric utilities. The two investor-owned utilities — TransAlta Utilities Corporation and Alberta Power Limited — are fully integrated since they generate electricity and provide bulk transmission and distribution to final consumers.

TransAlta provides service primarily to the southern and central regions of the province while Alberta Power serves the northern and some central regions. Edmonton Power and the City of Medicine Hat are municipally owned utilities which are also fully integrated. The seven remaining municipally owned utilities (Calgary, Lethbridge, Red Deer, Ponoka, Fort Macleod, Cardston and the Municipality of Crowsnest Pass) purchase their power wholesale from TransAlta Utilities and provide distribution service to final consumers.

Alberta's electric industry is regulated by the Energy Resources Conservation Board (ERCB) and the Public Utilities Board (PUB). The ERCB is responsible for approving generating plants required to meet forecast electric requirements. The PUB is responsible for setting consumer rates for the investor-owned utilities and for approving costs pooled under the Electric Energy Marketing Act (EEMA). Rates for the municipal utilities and their customers are set by their city councils.

The Electricity Policy Branch of the Department of Energy provides analysis and undertakes policy development on issues, policies and legislation affecting the generation, transmission, distribution and pricing of electricity in Alberta. The Branch also administers the Electric Energy Marketing Act and the Small Power Research and Development Act.

Coal-fired plants have traditionally been the most economical source of power and therefore provide 90 per cent of the electricity generated in the province. In addition, there are a limited number of gas-fired plants and hydro facilities.

Electric Energy Demand — During the 1991-92 fiscal year, demand for electric energy in Alberta increased by 4.7 per cent compared to 4.5 per cent in the previous fiscal year.

Changes in Electricity Bills — Electricity bills showed moderate increases during the 1991-92 fiscal year as shown in Figure 12. The increases resulted partly from the addition of Edmonton Power's first Genesee unit to the ratebase in 1990. The costs of new generating facilities are phased in over two years. The balance of the increase was due to new transmission and distribution facilities and increases in operating costs.

Figure 12
Increase in Electricity Bills — March 31, 1991 to March 31, 1992

	Residential	Commercial	Industrial	Farm
TransAlta Utilities (retail)	6%	6%	6%	6%
Alberta Power	5%	12%	11%	3%
City of Calgary	4%	4%	4%	–
City of Edmonton	0%	0%	0%	–

Note: The increases vary significantly depending on the time period chosen. For example, Edmonton Power had an average increase of 8 per cent that was effective April 1, 1992.

Electric Energy Marketing Act (EEMA) — Responsibility for administering EEMA was transferred to the Department of Energy from the Alberta Electric Energy Marketing Agency in July 1991. The transfer resulted in staff reductions and will produce financial savings of approximately $400,000 a year.

The Act was introduced in September 1982 to provide a mechanism to reduce the disparity of electrical rates charged to similar consumers in different parts of the province. The basic concept of the Act is to recover the costs of generation and transmission facilities from electricity consumers province-wide independent of ownership, franchise boundaries or geographic location. The utilities under EEMA are TransAlta Utilities Corporation, Alberta Power Limited and Edmonton Power.

In March 1992, the Minister of Energy established a seven-member Review Panel to examine EEMA. The panel was to request written submissions from interested Albertans and hold public meetings. It was asked to determine the following:

- Are the original objectives established for EEMA still valid for Alberta in the 1990s?
- If the original objectives are still valid, is the current implementation of EEMA the most effective and fair way to achieve EEMA's objectives?
- If the original objectives and/or implementation are not valid, what are the alternatives to EEMA?

Small Power Research and Development Program — The principal objectives of the Small Power Research and Development Program are to help determine the role of renewable small power in meeting the future requirements of the province and to help develop a renewable energy industry in Alberta. The program allows for 125 megawatts of renewable small power to be added and provides for an incentive power purchase price. The program, first of its kind in Canada, is fully allocated.

A review of the program was completed in 1991-92. Its regulations were amended to help project development. The first five projects were commissioned under the program including two hydro developments (Dickson Dam and Belly River) and three small wind turbines on farms in southern Alberta.

Regulatory Review — A regulatory review of the electric power industry was started in 1990 to consider stakeholder concerns with the facility planning and approval process. The main concerns expressed were:

1. Perception by some stakeholders that there is a lack of coordination between the ERCB and the PUB. The ERCB establishes the need for new facilities and approves them. The PUB regulates cost recovery for new facilities.
2. Perception by some stakeholders that EEMA has a detrimental impact on planning and accountability.
3. Concern by some stakeholders about the planning process.

In the spring of 1991, the Electricity Policy Branch formed a task force consisting of electric utilities, consumer groups and other interested parties to address these concerns. A series of workshops were held to exchange views and explore alternatives to the existing industry structure and method of regulation.

Fuel Use Policy And Export Policy Review — The government announced its intention in March 1992 to review the fuel use policy for electrical generation which was established in May 1974. The policy provided that coal would be the preferred fuel over natural gas for the baseload generation of electric power. The policy provides guidelines for the Energy Resources Conservation Board when it makes decisions or recommendations for new electrical generation.

The review will also assess Alberta's policy on the export of electricity. The policy, announced in 1982, allows electricity exports only if the power is surplus to Alberta's needs and the sale of power is beneficial to Alberta consumers. Both reviews will involve consultation with stakeholders including electric utilities, gas and coal producers, independent power producers and electricity consumers.

Cogeneration Study — A policy study, completed in March 1992, found that there is a large technical potential for cogeneration and waste energy generation in Alberta. It concluded, however, that the economic potential is small at present because of low electricity rates and no requirements for additional power. When power is required in the future, certain sources of cogeneration could be competitive.

Areas of policy concerns raised in the study included pricing and the timing for construction of cogeneration facilities. The study also identified the need to review the province's fuel use policy for power generation, and the electricity export policy. It found that generation of electricity from waste is significantly more costly than generation of electricity from conventional sources such as coal and gas, and from cogeneration.

Cogeneration is the simultaneous production of electric and thermal energy from a single fuel source.

Energy Efficiency and the Environment

The environmental concerns that influenced the energy agenda in 1990-91 continued to grow in 1991-92. Energy-related environmental concerns stem from potential impacts from the development, production and consumption of energy resources. The Department of Energy has addressed these concerns with a focus on integration of resource development and environmental protection and with management of atmospheric emissions associated with energy production and use.

Integrated Resource Management — The department subscribes to the philosophy of integrated resource management to ensure that land-use and resource-use decisions are made in the broader context of multiple land use. This presents the department with the opportunity to review land and resource management policies, programs and objectives of participating government agencies. Such reviews ensure that programs are consistent with the government's overall plan for the management of Alberta's mineral resources. The department reciprocates by sharing information on energy or mineral resource management initiatives with these agencies.

Integrated resource management is achieved by the department through a number of methods, the most formal of which is participation in the province's Integrated Resource Planning program. The Mineral Resources Division coordinates the department's participation in the program.

In the 1991-92 fiscal year, the division worked to maintain opportunities for industry to gain access to, explore for and develop the mineral resources in each planning area. Progress was made on 13 Integrated Resource Plans (IRPs), one of which was approved for implementation. As well, the division participated in one major plan review which began in 1991. In all, 28 IRPs have been approved.

The department also participates in integrated resource management through a number of interdepartmental referral processes. During the year, 124 referrals were received for review and comment.

These referrals included: one reclassification of land pursuant to current coal policy; four preliminary disclosures to government by proponents of major energy or mineral development proposals; six Environmental Impact Assessments; 41 applications for surface dispositions for commercial tourism and recreation leases; 26 applications to designate lands for uses such as future parks, ecological reserves or wilderness and natural areas; 2 industrial development applications; 15 land transfer requests; and 29 miscellaneous applications. Each referral was reviewed for its impact on access for existing or proposed mineral development activity.

The Mineral Resources Division also participated in three regional integrated decisions (RIDs), which are similar to integrated resource plans but with a local focus. The RIDs were designed to resolve oil and gas development access issues in environmentally sensitive and ecologically significant areas.

Clean Air Strategy — Public consultations on the Clean Air Strategy for Alberta (CASA) were held across Alberta during 1991. These included workshops, public meetings and written submissions from stakeholder groups. The objectives of CASA were:

- To help identify and clarify issues associated with energy production and use which need to be addressed through a clean air strategy,
- To outline practical, achievable actions for consumers and producers to take to reduce emissions, and
- To develop policy and program recommendations for government.

In September 1991, the 18-month consultative phase of the Clean Air Strategy was completed at a summary workshop in Calgary. In November, the Advisory Group to CASA, co-chaired by the Department of Energy, presented its final report to Alberta's Energy and Environment Ministers. The

Integrated Resource Plans represent a comprehensive and collective approach to decision-making on the use of public land and resources. Information about resources and land-use activities is considered in the process, as are the views of interested government agencies, municipal authorities, interest groups and the public.

The Clean Air Strategy For Alberta is designed to encourage public discussion on air emissions resulting from the production and use of energy. The initiative was in response to continuing national and international discussions about the impact of fossil fuels on global warming, acid deposition and smog.

report identifies a range of air management challenges in Alberta. It outlines a series of goals and activities to help government address the challenges. It proposes an air quality management system for identifying problems, setting priorities, allocating resources, developing plans and involving a full range of stakeholders.

A key element of the CASA report was the development of an Alberta position on greenhouse gases. Representatives from the Departments of Energy and Environment, environment organizations and the energy industry agreed on a common objective of moving Alberta toward reduction of greenhouse gas emissions from current levels through a number of cost-effective and efficient actions. This position was subsequently adopted by the Alberta Government.

The Department of Energy provided CASA with secretariat support during this period and was an integral part of the various working groups.

National Coordination on Climate Change Initiatives — The department participated in numerous activities related to global climate change at both the national and international levels throughout 1991-92.

The Environmental Affairs Branch participated in the Provincial-Territorial Committee on Climate Change (PTAC), established to advise the federal government on issues related to the drafting of an international climate change convention. Consisting of representatives from Canada's energy and environment departments, the committee offered advice on how the country's international commitments should address the important relationship between energy and climate change.

On two occasions, the Department of Energy represented PTAC at the International Negotiating Committee which was drafting the Climate Change Convention.

Western Air Quality Issues — The Department of Energy also played a key role in the development of western regional strategies on climate change and air quality. The Western Provincial-Territorial Air Quality Issues Coordinating Committee, consisting of representatives from the energy and environment departments of the four western provinces, the two territories and the federal government, was formed in February 1991. Since that time, the committee has met on several occasions to discuss energy-related atmospheric issues of concern to the participating jurisdictions. A significant accomplishment of this committee was development of a database for climate change activities in these jurisdictions and agreement to expand the database to include other air quality issues.

Environmental Legislation — The Department of Energy was extensively involved during the year in consultative activities concerned with the development of the Alberta Environmental Protection and Enhancement Act. The Department of Energy worked with representatives of the energy industry, the Energy Resources Conservation Board and Alberta Environment with the goal of creating sound environmental legislation which considers the impact that such an act would have on energy development in the province.

Southwest Alberta Renewable Energy Initiative — The Southwest Alberta Renewable Energy Initiative (SWAREI) was created in 1989 to encourage development of the abundant wind and solar energy resources in the Pincher Creek-Crowsnest Pass area and to help diversify the economy of the region. SWAREI is the largest renewable energy program in Western Canada. It offers three types of assistance:

- Financial assistance, from the Alberta Heritage Savings Trust Fund,
- Power allocation to the province's electrical grid, and
- Information dissemination.

Two new projects were approved in 1991-92, bringing the SWAREI total to 10 projects. Over the year, the renewable energy information centre in Pincher Creek fielded over 450 enquiries about renewable energy, provided 6 workshops on renewable energy and energy efficiency, and participated in several related conferences, expositions and trade fairs.

Greenhouse Gases — When certain atmospheric gases trap radiated heat in the atmosphere, a "greenhouse effect" may be created, possibly leading to global warming, an increase in the earth's lower atmospheric temperature. Carbon dioxide is considered the major greenhouse gas.

Energy Efficiency

The Department of Energy encourages and promotes the wise and efficient use of Alberta's energy resources. It develops and operates energy efficiency awareness, information and education services for all types of energy users. Services are available for the general public, business and industry, the transportation sector and for students and teachers. All services are available at no charge.

Information Services — The Energy Matters telephone enquiry service received more than 4,000 calls on home energy efficiency questions during 1991-92. More than 160,000 copies of publications were distributed through building supply and hardware stores and other outlets.

Technical Services — Energy audits, conducted on request from business, industry and institutions, identify potential energy-efficiency improvements through on-site analysis. Energy Efficiency Branch staff use two computer-equipped energy buses to monitor energy use, determine steps to reduce energy costs and make recommendations. In 1991-92, 72 buildings of various types were visited. Potential annual energy cost reductions of $1.2 million (17.8 per cent of total annual costs) were identified, involving easily implemented measures. More than 2,200 buildings have been audited since this program was introduced 10 years ago.

A transportation energy audit program has been offered to vehicle fleet operators. During the past fiscal year, three such audits were completed. Potential annual fuel cost reductions of $46,500 (53 per cent of total annual costs) were identified. To date, 24 fleets of various types have been analyzed, identifying over $500,000 in potential annual savings. During the year, approximately 80,000 Alberta drivers received fuel economy calculators and other materials to help monitor and improve fuel efficiency.

Education Services — More than 14,500 Alberta students received energy-saving messages in their classrooms through dramatized presentations by department staff. Alberta educators received instructional and curriculum resources, including 2,700 instructional resource kits, to help them teach the importance of energy efficiency to more than 77,400 students.

Energywise and Demand Restraint — The department participated in further development of an energy saving program within government called Energywise. The program emphasizes fuel efficiency in the provincial public service as well as activities targeted to large employers and commercial fleet operators.

The department participated in national coordination of the petroleum demand restraint initiative started in response to the Persian Gulf Crisis. It focuses on assuring oil supplies for all parts of Canada in an emergency. The department also provided assistance to Alberta Power Limited in a program to help power consumers to use electricity more efficiently. The department continued active interprovincial and federal-provincial coordination on energy efficiency issues.

Finance and Administration

Finance and Administration provides a core group of services to the Departments of Energy, and Forestry, Lands and Wildlife. This approach is unique in the provincial government, and the operations are highly effective.

The services provided by the five divisions within Finance and Administration include accounting and budgeting, internal audit, information and office support, human resources, and electronic information and data processing. The methods and systems used are innovative, efficient and cost-effective.

Automated Information Systems — By the end of the fiscal year, Automated Information Systems supported 32 major computer systems for the departments. The Mineral Revenues System was enhanced and a new corporate accounts receivable system added. In addition, an improved Oil and Gas Sales System was started, helping to streamline the sales process for oil and gas agreements.

Work continued on expanding the telecommunications network and electronic office systems. These provide electronic mail and word processing functions to the departments' Edmonton offices and regional locations.

Financial Services — The first part of an initiative to replace the Main Accounts Receivable System with the Corporate Accounting and Recording System was completed. This involved creating a computer link with all systems used by the departments for collecting and reporting revenue.

General Services — An extensive review of the copying, duplicating and printing needs of the departments was undertaken. Based on this, a comprehensive strategy was developed for the departments to increase the efficiency level and reduce expenditures.

A subscription database was installed in Library Services to coordinate purchase and sharing of periodicals. This cost-saving initiative has allowed divisions to re-allocate funds formerly spent on such items as magazines and newsletters, without losing access to these subscriptions.

The Records Management Program won the International Distinguished Achievement Award from the Olsten Corporation for excellence in records management.

Human Resources — Human Resources worked closely with the departments to provide consultation and administrative services related to all aspects of human resources. The most current knowledge and resources available were provided to the departments, which allowed them to meet their human resource needs within a period of restraint. The Forest Technology School in Hinton, which is part of Human Resources, continued to offer facilities and services for training, meetings, conferences and seminars.

Internal Audit — Operations of the departments were assessed using standard audit processes. Senior management reviewed the results and recommendations, and made changes where necessary. Recommendations were made to the departments for development of new computer systems. This reduced the potential for duplication and made sure that basic department standards are met.

Appendix

Syncrude Project

The Syncrude Project is the largest of its type in the world, producing more than 11 per cent of Canada's total crude oil requirements. Syncrude uses huge draglines, bucketwheels and conveyors to mine oil sands north of Fort McMurray. Through the Alberta Heritage Savings Trust Fund, the Province of Alberta holds a 16.74-per-cent equity interest in the Project. Alberta receives a joint venture payment equal to 50 per cent of the Project's deemed net profits in lieu of a royalty. The province has to date received more than $1 billion in joint venture payments from Syncrude.

Alberta's Syncrude Project investment is managed by Alberta Oil Sands Equity.

At the end of March 31, 1992, Syncrude provided direct employment for 4,431 employees and another 900 contract people. The project generates 16,000 direct and indirect jobs annually in Canada and $1 billion annually in spending for the Canadian economy.

1991-92 Highlights — Production of synthetic crude oil for the fiscal year 1991-92 totalled 62 million barrels compared with 61.9 million barrels in 1990–91. This production was achieved despite operating problems which took parts of the plant out of service for a total of 82 days between August and October 1991. Production represented approximately 13 per cent of Alberta's annual crude oil and equivalent production.

A total of 143 hectares of mined land was planted with seedlings or transformed into grassland in 1991, compared to 40 hectares reclaimed in 1990. Since plant start-up, more than $100 million has been spent on environmental control technology and reclamation activities.

Although synthetic crude oil prices have dropped 50 per cent since 1985, Syncrude has offset this adverse impact by increasing production by almost 30 per cent and tightly controlling operating costs. Unit operating cost reductions have been achieved despite increased overburden removal costs due to a mining waste-to-ore ratio which has doubled over the past five years.

The Heritage Fund's income from its equity interest in Syncrude totalled $43.3 million in 1991-92, down from $82.1 million in 1990-91. The primary cause of this income decline was a $4 per barrel drop in synthetic crude oil prices after the Persian Gulf war to an average of $22.45 per barrel in 1991-92. In total the Heritage Fund has received income of $561 million from its investment in Syncrude since production began in 1978.

OSLO Commercial Project

OSLO is an acronym for Other Six Leases Operation, referring to the other six leases owned by the original Syncrude members. As envisaged, the OSLO Commercial Project would consist of an oil sands mining operation across the Athabasca River from the Syncrude site, north of Fort McMurray connected by pipeline with a proposed bitumen upgrader at Redwater, about 60 kilometres northeast of Edmonton.

The Province of Alberta, through the Alberta Heritage Savings Trust Fund, has a 10-per-cent equity investment in the Project. This investment is managed by Alberta Oil Sands Equity. The federal government withdrew its funding commitments to the Project in February 1990, but provided $40.9 million towards completion of the $117 million engineering studies. Alberta agreed to provide up to $46.8 million of the $130 million from the General Revenue Fund.

1991-92 Highlights — Work was completed on detailed engineering studies. These studies predicted that the project would cost $5.4 billion and produce 80,000 barrels of synthetic crude oil per day.

In early 1992, the OSLO participants made a decision to suspend work on the Commercial Project. The value of the Heritage Fund's $6.8 million investment in the Project was written down to nil, effective March 31, 1992. The write-down reflects the low probability that the project will proceed in the near term.

Lloydminster Bi-Provincial Upgrader

The Lloydminster Bi-Provincial Upgrader was designed to produce 46,000 barrels of synthetic crude oil per day from heavy oil and bitumen reserves in Alberta and Saskatchewan. Construction proceeded during the year under the management of Husky Oil Ltd. on behalf of a joint venture consisting of Husky and the governments of Alberta, Saskatchewan and Canada.

Alberta holds a 24.17-per-cent interest in the project through the Alberta Heritage Savings Trust Fund. This investment is managed by Alberta Oil Sands Equity.

1991-92 Highlights — Higher-than-expected costs for construction, management, materials and other factors raised the original project cost estimate from $1.27 billion to a forecast $1.63 billion. Alberta is responsible for a total of $98 million of the $365-million cost increase. This funding consists of 24.17 per cent of $175 million ($42.3 million) and 29.29 per cent of the $190 million (55.7 million) second overrun. The increase in Alberta's share resulted from a decision by the Government of Saskatchewan not to fund any of the second overrun.

This funding is being provided by a further equity investment from the Heritage Fund which will bring the Fund's total commitment to about $404 million. In accordance with accounting policy, the value of the Heritage Fund investment has been written down by $88.2 million to $221 million because of the cost overruns.

Construction of the project was almost 90-per-cent complete by March 31, 1992.

The Upgrader is the first Canadian megaproject to have almost all (97 per cent) of its engineering done in Canada. The workforce, which peaked in December 1991 at about 3,700, was 100 per cent Canadian. Native participation, including full-time and part-time workers, reached 12.8 per cent of the workforce.

The Upgrader will generate approximately 300 full-time positions, plus 100 contract maintenance position as well as an additional 800 contract maintenance positions for a 20-day plant turnaround every 18 months.

Financial Statements

Alberta Department of Energy
Statement of Revenue
For the Year Ended March 31, 1992
(Unaudited)

	1991-92 ($000)	1990-91 ($000)
Royalties		
Crude Oil	1,037,611	1,325,194
Natural Gas and By-products	839,277	1,080,352
Synthetic Crude Oil & Bitumen	30,590	39,013
Coal	26,491	14,671
Other Royalties and Fees	4,403	4,811
	1,938,372	2,464,041
Crown Sales, Oil and Natural Gas Agreements and Oil Sands Agreements	261,502	415,596
Rentals and Fees		
Oil and Natural Gas, and Synthetic Oil	101,081	93,897
Coal and Other	3,597	3,752
	104,678	97,649
Mineral Taxes	75,217	76,053
Expenditure Recoveries	341	1,155
Miscellaneous	473	642
Gross Revenue	2,380,583	3,055,136
Add (Deduct) Incentive Programs		
Exploratory Drilling	0	501
Geophysical	0	(1)
	0	500
Net Revenue	**2,380,583**	**3,055,636**

Prepared by Revenue Branch
Financial Services Division
December 1992

Alberta Energy
Statement of Expenditures[1]
For the Year Ended March 31, 1992
(Unaudited)

	1991/92 ($000)	1990/91 ($000)
Finance and Administration Services Division	6,799	6,553
Other Divisions		
Mineral Resources	7,474	8,154
Mineral Revenues	14,341	13,622
Markets, Supply and Industry Analysis	3,419	2,734
Sustainable Energy Development	7,218	9,000
Executive Offices	1,304	1,305
Special Warrants and Special Programs		
Assistance for Oil Sands Projects	25,189	4,994
Total Expenditures	**65,744**	**46,362**

Prepared by Revenue Branch
Financial Services Division
December 1992

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[1] **Note 1: Statement Of Expenditures:** Alberta Oil Sands Equity, Alberta Oil Sands Technology and Research Authority, Alberta Petroleum Marketing Commission, Alberta Petroleum Incentives Program, Alberta Electric Energy Marketing Agency and Alberta Public Utilities Board are not included in the Statement of Expenditures.

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